International Journal of Mechanical and Production Engineering Research and Development (IJMPERD)
ISSN (P): 2249-6890; ISSN (E): 2249-8001
Vol. 9, Issue 2, Apr 2019, 759-768

EFFECT OF POLYACRYLAMIDE WITH ZnO NANO AQUEOUS SOLUTION ON THE CHEMICAL FLOODING METHOD WITHENHANCED OIL RECOVERY (EOR) – AN EXPERIMENTAL AND MODELLING STUDY

NIZAR JAWAD HADI, MOHAMMED HAMZA AL-MAAMORI & SAJA HAIDER MOHMMED

Department of Polymer and Petrochemical Industries, Collage of Materials Engineering, University of Babylon, Iraq

ABSTRACT

This work studied the effect of polyacrylamide (PAM) with ZnO nanoparticles (NPs) solution on the recovery of crude oil in tertiary stage. Shear viscosity due to shear rate and salt concentration, also shear stress with different shear rates were tested. Core flooding test used to check the ratio of oil produced from Core as porous media. Ansys-Fluent 16.1 by program based on finite volume with the help of experimental data was used to visualize the interphase between injected fluid and oil in porous media. The results show that the shear viscosity decreases and shear stress increases with the ZnO NPs increasing. Non-Newtonian flow and shear thinning phenomena dominate the viscosity curve. 1000ppm PAM with 0.005%ZnO/brine water give 80.32%oil production, low interfacial tension and uniform interaction in Oil Volume. Fraction between injected solution and displacement fluid form Core by Ansys.

KEYWORDS: PAM with ZnO Flooding, Non- Newtonian Flow, Viscosity, Surface Tension, Oil, Core Flooding Test, Numerical Simulation by Fluent 16.1 & Oil Volume Fraction

Received: Feb 15, 2019; **Accepted**: Mar 08, 2019; **Published**: Mar 29, 2019; **Paper Id**.: IJMPERDAPR201975

Original Article

INTRODUCTION

Primary oil recovery extracts about 15% from it, by pressure within reservoir [1]. Secondary recovery depends on injected gas or water to extract more amounts from oil about 30% [2]. High amount of oil remains on reservoir required, mixed with chemicals and injected fluid like nano particles [3], surfactant [4], polymer [5] etc. Tertiary recovery or enhanced oil recovery (EOR) was used to increased oil extract from porous media by increasing pressure of reservoir [6]. Mixed nano particles (NPs)with water to make nano fluid solution was used to EOR because, small particle size less than 100 nm that make it easily to penetrate in pores of porous media [7], increase disjoining pressure [8], decrease interfacial tension [9], wettability alteration [10], increase viscosity [11] and prevent asphaltene precipitation [12]. MixedNPs with water lead to increased viscosity, which decreases mobility ratio with lower viscous finger [13], and decrease relative permeability of oil less than water [14]. More oil recovery was obtained by made surface of porous media transform from oil wet, which have contact angle more than 90° to water wet, that has contact angle less 90°[15]. Surfactant with NPs was used to change wettability of porous media to more water wet, by decreasing the contact angle [16]. Physical and chemical properties of nanofuid injected in sandstone rock was studied experimentally and numerically[17], by observed porosity and permeability, and relative permeability of oil was decreased, wettability and additional oil recovery was increased to 20% with high concentration of NPs, maximum NPs added not exceeded (2-3) % and there was good agreement between

experimental and numerical results. Using solution from metal NPs and anionic surfactantas injected fluid to EOR, was studied by [18], and obtained increased additional oil recovery from porous media of about 35%. Injected polymer was one of the chemicals used to EOR. Mechanical degradation was occurring in polymer flooding, due to high shear rate in reservoir that lead to decreased viscosity of aqueous solution [19]. Prevention of mechanical degradation and improvement in shear thinning effect at low shear rate was obtained by mixed Sio2 NPs with polyacrylamide (PAM), at low shear rate [20]. Modelling multi-phase flow in porous media was very difficult, because this is related to ability of injecting fluid to release another that remained in porous media [21],[22]. Applied water-oil displacement flow in a downward inclined pipe, computational fluid dynamics (CFD) by Volume of Fluid(VOF) method was used as the multiphase model. Three flow patterns were obtained and the simulated data were favorably matched with the experiment results. Further efforts were made, where parametric studies were concerned, including the effects of pipe diameter, inclination angle, and water inlet velocity on the displacement process. It was concluded that the displacement efficiency can be improved by increasing the water inlet velocity, and the increasing pipe inclination angle may lead to the instability of the interface[22].

In this present work, polyacrylamide (PAM) was mixed with NPs solution with different concentration. Rheological, chemical, physical and petro physical properties were measured. Experimental flooding was performed to check oil recovery. Computational Fluid Dynamics (CFD) by FLUENT16.1 was used to investigate volume fraction of oil-injected solutions. Volume of Fluid (VOF) method, including effect of interfacial tension and viscosity was applied to produce viscous finger difference between brine water and polymer with NPs solution.

MATERIALS AND METHODS

Polyacrylamide (PAM) with average molecular mass ≥ 2500000(g/mol), 1.181(g/mol) density, 160C° glass transition temperature(Tg) from (china). Zinc oxide (ZnO) with 99.82% purity, 30±5 (nm) particle size, 4.4(g/mol) density and 955 C° melting point from china. Sodium dodecyl sulfate (SDS) with 94% purity, 1.02(g/mol) density, 206 C° melting point and 2888.40(g/mol) molecular weight from china. Tap water and brine water. Experimental oil from Basra Oil Company / Research and Quality department with viscosity 3.115 Cp and density 0.9993 g/cm^3 at 25C°and the sandstone (Core) from Nasirya oil reservoir cut from 2020m depth.

Brine Aqueous Solution

Brine water was prepared by mixing 20% of Nacl with tap water using magnetic stirrer for5min.

ZnO Nano Fluid Solutions

ZnO nano particles with different weightsare shown in Table 1, mixed by using magnetic stirrer for (15) min with tap and brine water, separately. Nano particles spread within solution, which became white with cloudy in shape. Sodium dodecyl sulfate (SDS) was added as surfactant to ZnO NPssolution by mixing for (10) min on magnetic stirrer. Obtained foam appears over solution, which entirely spreads within ZnO solution. Used ultrasonic with conditions (50) energy, (25-50) C° temperature for (35) min to obtain highly spread ZnO within solution.

ZnO Nano Fluid Solutions with Polyacrylamide (PAM)

Slowly, add (1000) ppm PAM with each solution of Zno NPs, which was prepared according to Table 1. PAM was added to the solution for (35) min on magnetic stirrer to obtain high dissolve within solution.

Table 1: Weight % of ZnO Nano Particles to Prepared Nano Fluid Solutions

Aqueous Solution (50)ml	Weight (%)	ZnO (g)	SDS (g)
Tap water	0.005	0.0025	0.005
Tap water	0.01	0.005	0.01
Tap water	0.05	0.025	0.05
Tap water	0.1	0.05	0.1
Tap water	0.2	0.1	0.2
Tap water	0.3	0.15	0.3
Brine water	0.005	0.0025	0.005
Brine water	0.01	0.005	0.01
Brine water	0.05	0.025	0.05
Brine water	0.1	0.05	0.1
Brine water	0.2	0.1	0.2
Brine water	0.3	0.15	0.3

Rheological Properties

Brookfield cone / plate viscometer with spindle: 41Z was used to measure shear viscosity, shear stress of PAM with ZnO NPs/ tap or brine water, due to the shear rate (25-250) $s^{-1.}$

Physical Properties

Density

Within digital accuracy = ± 0.0001 g/cm3, type GP-120 S, made in Matsu haku, China that was based on ASTM D-792. Test density of PAM with ZnO NPs/ tap or brine water.

Surface Tension

With JZYW-200B Automatic Interface Tensiometer from BEIJNG TEST CO., LTD China, testedsurface tension and interfacial tension (IFT) of PAM with ZnO NPs/ tap and brine water at 25C°.

Petro Physical Properties

This test was available in Basra Oil Company / Research and Quality department-Nahran Omar.

Porosity

ULTRA PORE 300. TEMCO DIV. OF CORE LAB. TULSA, Oklahoma. www.temco.com, was used to test porosity of core sample.

Permeability

Ultra Perm 550, was used to measured permeability of air and liquids.

Core Flooding Test

Core was cleaned by methanol, placed the core for 10 hour at 125 °Cto dry it, saturated the dried core by brine water, weighed after and before saturated, put inside accumulative filled by brine water and weighed again. In this stage, we can determine pore volume (PV), porosity and permeability for air and liquid. The table4shows that. Put the core sample inside core flooding test, reservoir pressure was applied on it, displacement of brine water done by experimental oil. The residual water saturation (Swi) and initial oil saturation (Soi) were calculated that appear in table5. Experimental

flooding was held on two steps. Firstly, injected brine water and secondly, by brine water and when oil not recovered. Secondly, injected 1000 ppm PAM with 0.005% ZnO/brine water as tertiary recovery. Flooding carried out by removing oil from core, at flow rate (6) cm3/min derived from average of all south oil reservoirs. Magnitude of pressure (1500) Psi related to permeability of core. Flooding continued and calculated the time to reach break through point, which represents the first drop of water with oil. Displacement continued until water read with total volume equaled 99.9%, and then calculatedthe oil recovery (Table 5).

Computational Fluid Dynamic (CFD) Analysis by FLUENT16.1

Modeling

Figure1, shows the sandstone core used in this study. Geometry consists of 2-D, same dimension of core that was used in experimental flooding. Oil firstly filled Core and theninjected brine water and 1000ppm PAM with 0.005%ZnO/brine water.

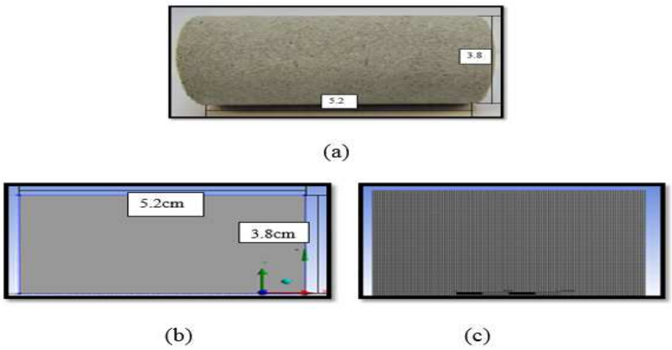


Figure 1: (a) Sandstone core with (5.2) cm length and (3.8) cm diameter, (b) Geometry of model and (c) Meshing of model

Mesh

Mesh was applied to divide the geometry of model, as show in Figure (1, b) into number of elements and nodes, based on finite volume method. Mesh is completed by depending on face sizing, body sizing, edge sizing, face meshing and refine. Figure (1, c), shows the mesh of 2-D model, consists of elements (8800) and nodes (8991).

Main Assumptions

A-Steady and laminar flow.

B- Viscosity depends on shear rate for 1000ppm PAM with 0.005%ZnO/brine water.

C- Power law model for 1000ppm PAM with 0.005%ZnO/brine water.

Governing Equations

Continuity Equation

$$\nabla u=0$$

Where, u is velocity of non-Newtonian 1000ppm PAM with 0.005%ZnO/brine water.

Momentum Equation

$$\rho \partial u \partial u+\rho u . \nabla u=\mu \nabla 2\ u-\nabla P$$

For steady non-Newtonian, 1000ppm PAM with 0.005%ZnO/brine water flow, momentum equation is write as,

$$u\partial u\partial x+v\partial u\partial y=(1\rho)\partial\tau xy\partial y$$

Where, u and v are the x and y velocity components respectively, τxy is the shear stress and ρ is the density of non-Newtonian 1000ppm PAM with 0.005%ZnO/brine water with pseudo plastic.

Power Low Model

$$\mu = K\gamma^{\cdot n-1}$$

Where μ is the viscosity, k is consistency index, γ is the shear rate and *n* is the power law index.

Boundary Conditions

A-Volume of Fluid (VOF) model is selected with number of phases=2. Then, select Implicit of VOF.

B- Viscosity, density, interfacial tension, n, k, porosity and permeability of injected solution are taken from experimental data that showed in Table3 and 4.

C- Operating pressure is set as (101325) and gravity is consider in Y-direction as (-9.81) m/s2

D- Select (6) cm3/min flow rate in inlet zone for brine water and 1000ppm PAM with 0.005%ZnO/brine water.

E- Wall be stationary and No-slip.

F- Pressure was selected as outlet.

G-Number of iteration is 60.

EXPERIMENTAL RESULT

Shear Viscosity

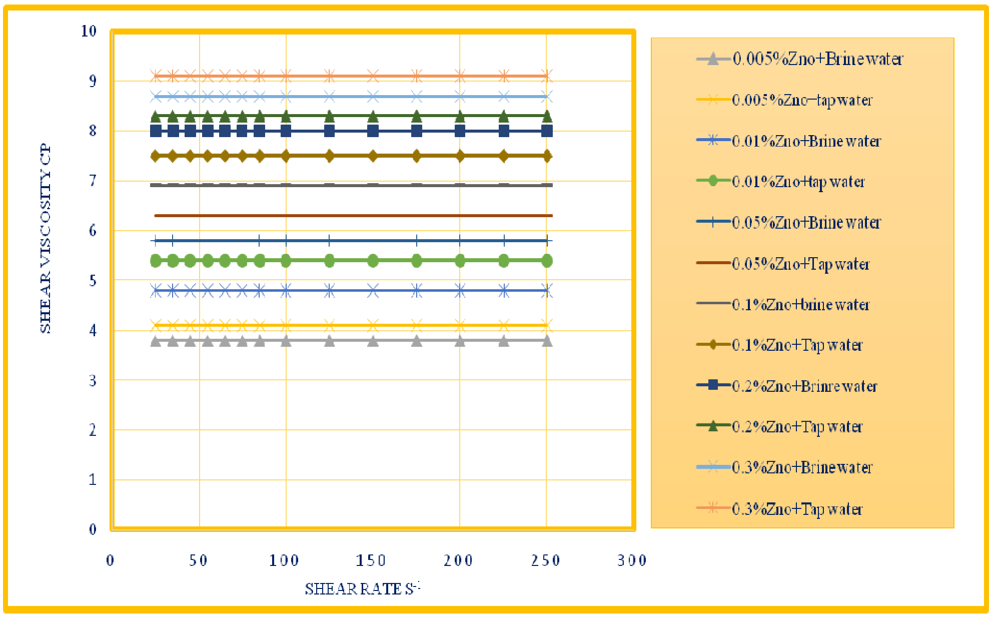


Figure 2: Shear Viscosity versus Shear Rate for different ZnO Aqueous Solution

Figure 2, expresses the relationship between shear viscosity and the shear rate for each types of ZnO Nps solutions with different concentrations. At a constant shear rate, shear viscosity of each solution is greater for larger ZnO NPs concentrations. Also, shear viscosity was constant with an increasing of shear rate in behavior of Newtonian. The brine solutions was lower shear viscosity values for all NPs solutions. White solution with foam was appeared at the surface of solution due to the use of Sodium Dodecyl Sulfate (SDS) as surfactant. This prevents agglomeration of ZnO Nano particles. Furthermore, these mechanisms help ZnO Nano to penetrate to small pores and movement oil from it.

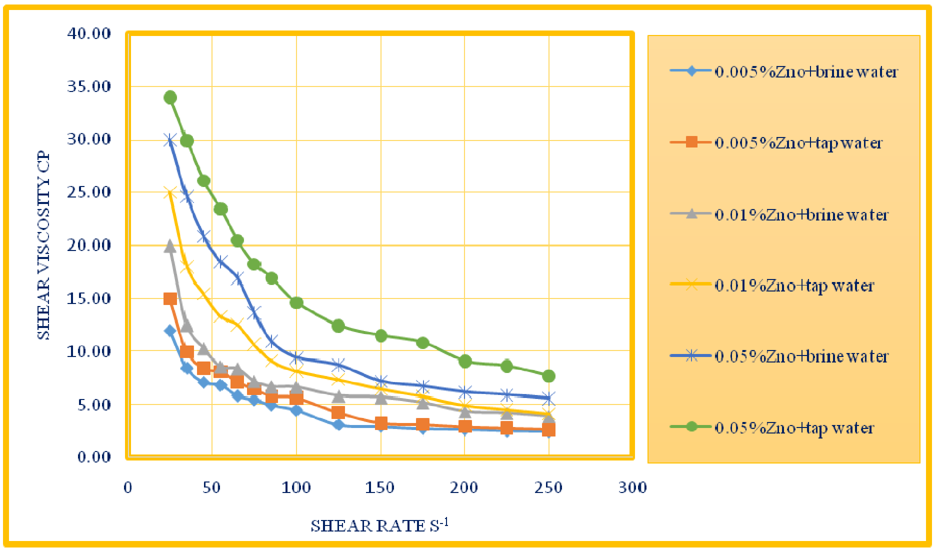


Figure 3: Shear Viscosity versus Shear Rate of (1000) ppm PAM with different ZnO Aqueous Solution

The data in Figure 3 indicates that shear viscosity decreases with the shear rate increasing for all 1000 ppm PAM with ZnONPs solutions. The shear thinning effect increases with the ZnO NPs increasing. At the same time, brine NPs solutions show lower shear viscosity values. The Non-Newtonian and shear thinning effects concentrated in the shear rate range (25-100) s-1, which is more suitable behavior to EOR. After 100 s-1 up to 250 s-1 shear rate of all solutions behave as Newtonian solutions. These solutions show higher shear viscosity as compared by shear viscosity in Figure 2.

Flow Curve

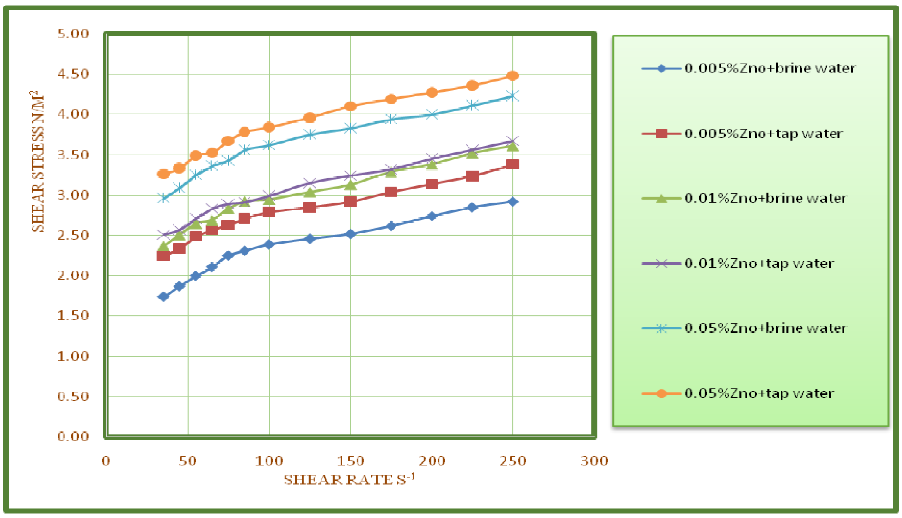


Figure 4: Shear Stress Against Shear Rate of different Zno Aqueous Solutions with (1000) ppm PAM

Figure 4, expresses that the shear stress increases with the shear rate increasing for all aqueous solutions. The behavior of shear stress consists of two zones. The first one ends before (100) s^{-1} shear rate with rapidly increasing and the second ends completely slowly at (250) s^{-1} shear rate. Shear stress resistance to shear rate increased by adding (1000) ppm PAM to ZnO Nps solutions. The low shear stress appears at low shear rate, which is also suitable to EOR. Brine Nps solutions appear low shear stress as compared by NPs with tap water.

Density

High density referred to the increasing interlink ages between chains. Dissolved (0.005, 0.01and0.05)% ZnO NPs by water led to increased water density as show in Table 2. Further increase of density was obtained for ZnO NPs solutions with 1000 ppm PAM, as show in Table 3. On the other hand, the dissolved chemicals by brine water led to lower density compared with the tap water.

Surface Tension

The maximum surface tension values were obtained for tap and brine aqueous solutions with 0.05%ZnO. While 1000 ppm PAM with 0.005% ZnO give higher surface tension values, tables 2 and 3, respectively show that. The power low index n decreases and viscosity consequences K increase with ZnO NPs increasing for tap and brine solutions. The values calculated for n and K comparable with the non- Newtonian flow behavior and shear thinning effect of PAM Zno. The lower n values the higher shear thinning effect, which is represented by 1000ppm PAM with 0.05% ZnO/tap water. The n and K values are very important data for Ansys program to simulate the flow in porous media in core test.

Table 2: Density, Surface Tension and Interfacial Tension for ZnONP Solutions

Aqueous solution	Density (g/cm^3)	Surface tension (mN/m)	Interfacial tension (mN/m)
oil	0.9993	35	-
Tape water	1.05	72	37
Brine water	0.65	25	20
0.005%Zno+Tap water	0.9756	26.3	25.9
0.01%Zno+Tap water	0.9814	27.5	27.2
0.05%Zno+Tap water	0.9936	31.2	30.9
0.1%Zno+ Tap water	0.9775	29.5	29.1
0.2%Zno+Tap water	0.9593	28.4	28.1
0.3%Zno+Tap water	0.9556	27.4	26.9
0.005%Zno+Brinewater	0.9751	25.2	24.7
0.01%Zno+ Brine water	0.9805	26.4	25.8
0.05%Zno+ Brine water	0.9928	30.3	29.5
0.1%Zno+ Brine water	0.9771	29.2	28.8
0.2%Zno+ Brine water	0.9593	28.3	27.8
0.3%Zno+ Brine water	0.9548	27.5	27.2

Table 3: Density, PH, Surface Tension for Zno Nano Fluid Solutions with PAM Concentrations

Aqueous Solution	Density (g/cm^3)	Surface Tension (mN/m)	Interfacial Tension (mN/m)	Power law Index (n)	Consistency (K) (pa. s^2)
1000ppmPAM+0.005%ZnO/Tap water	0.9989	34.4	18.9	0.3096	0.1289
1000ppmPAM+0.01%ZnO/ Tap water	0.9985	33.5	19.3	0.2643	0.2538
1000ppmPAM+0.05%ZnO/ tap water	0.9981	32.7	19.9	0.2338	0.5053

Table 4: Porosity, Pore Volume and Permeability

Samples	Porosity (%)	Pore Volume (PV)%	Permeability (mD) Ka Kl Ko		
Core2	27.9	15.52	201	30.76	4.40

Table 5: Oil Recovery

Sample	Solutions Dissolved by Brine Water	Oil Recovery from (OOIP)%	Additional Oil Recovery (OOIP)%	Saturation (%) Swi Soi Sor		
Core	Brine water	68.68at100% water cut	-	24	76	31.37
	1000PAM+0.005% Zno	80.32at 99.80 water cut	11.64			19.68

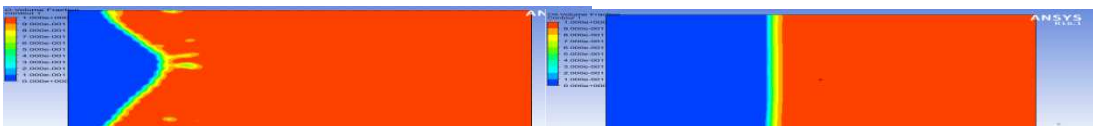
Experimental Flooding by Core Flooding

Viscosity increase is a critical value that is dependent on oil recovery. Porosity, pore volume and permeability of Core with air and solutions were tested as shown in Table 4. Irreducible water saturation (Swi) after injected oil on Coreis 24%, then initial oil saturation (Soi) is 76%. From Table 5, increase of water is cut to 100%, after injected brine water at magnitude of oil recovery about 68.68%. Injected1000ppm PAM with 0.005%ZnO NPs/brine water on the same core separately obtained high oil recovery of 80.32%, decreased water cut to 99.80%, lowering residual oil saturation(Sor) from (31.37 to 19.68)% andadditional oil recovery 11.64%. From these results, it is concluded that the ability of polymer with ZnONPs solution in low concentrations extracted high amount of oil from porous media, as compared by brine water.

QUALITATIVE NUMERICAL RESULT

Oil Volume Fraction Contour

Simulation oil released from porous media was dependent on viscosity of injected fluid. This agrees with that [23]. Viscosity of aqueous solution was depended to make simulation of core sample as porous media. In addition to interfacial tension that effect on wettability of core surface, which was also studied by [24]. Oil is 3.115 cp, which is more viscous than brine water with 0.55 cp viscosity and 20 mN/m interfacial tension, which results high mobility ratio, easily movement in porous media, no slug solution, high permeability when pushing oil forward, and the ability to wetting the surface was reducing. Figure 5 (a), shows clear viscous finger with unstable contact region between injected fluid and local oil. This result is comparable with [25], represents clear interface region between two fluids with amount of sharp fingers that result from low liquid viscosity. Parabolic velocity profile of brine water accelerate reach to break through point, resulted in less oil extracted, low sweep efficiency and remains high amount of oil in porous media. Figure5(b) shows the reduced viscous finger with stable contact region between injected fluid and local oil, with increase concentration. This result is similar to [26], in which appear fewer viscous fingers when viscosity of the introduced fluid was higher than viscosity of oil with stable displacement oil.



(a) (b)

Figure 5: Visualization of Oil Volume Fraction Contour for Core Injected by (a) Brine Water, and (b) 1000 ppm PAM with ZnO NPs /Brine Water

CONCLUSIONS

Experimental study was conducted with PAM with ZnO NPs solutions of rheological properties with shear rate (25-250) s^{-1} at 25C°. Physical, petro physical properties for Core and core flooding test were tested. Also, numerical simulations to visualize the contact zone between injected fluid and oil in porous media. From this work, high shear viscosity, shear stress with shear thinning behavior and low salt effect were obtained by PAM. With high concentrations, using 1000ppm PAM with 0.005%ZnO solution, give low interfacial tension, high oil recovery of about 80.32% from Core, stable contact zone with no viscous finger between injected fluid and displacement fluid. These results were useful in experimental flooding under highsalinity reservoir oil of south Iraq.

ACKNOWLEDGEMENTS

The authors would like to thank the Department of Polymer and Petrochemical industries, College of Materials Engineering/University of Babylon and Basra Oil Company/Research and Quality department-Nahran Omar.

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